Adaptation of Wholesale Power Markets: Intermittent Generation and Security of Supply Considerations

Paul L. Joskow
MIT
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OUTLINE

• Current trends in wholesale market design and ongoing enhancements
  • Focus on North America and European Union
  • Short-term markets
  • Investment and Security of Supply (Resource Adequacy)
  • Decarbonization and intermittency

• Rolling Blackouts in California and Texas
  • California: Solar dominated VRE
  • Taxes: Wind dominated VRE with rapidly growing solar capacity

• Lessons Learned for Wholesale Market Design Enhancements from California and Texas
Evolution of Wholesale Market Designs

1990s to ~2015

• Restructuring for competition
• Promote competition --- focus on refining short-term wholesale markets
• Geographic expansion of market areas (market integration)
• Built around dispatchable thermal generation
• Limited consumer interaction
• Transmission congestion and reliability
• SoS --- less attention due to excess capacity

Current Foci

• Security of Supply (SoS or “resource adequacy”)
• Decarbonization via deep penetration of wind/solar
• Harmonize SoS and Decarbonization goals
• Integration of capital intensive and zero MC intermittent wind/solar generation and storage: operations and investment
• Facilitate active consumer interactions (PV, storage, demand response)
• Transmission investment to better access and utilize wind/solar resources and support reliability

Based on Roques 2019
EU-ENTSO – 42 TSOs in 35 Countries

GB: 4
Germany: 4
Austria: 2
New EU Market Rules Effective January 1, 2020

These changes will adapt current EU market rules by:

- allowing electricity to move freely throughout the EU energy market through cross-border trade, more competition and better regional cooperation;
- enabling more flexibility to accommodate an increasing share of renewable energy in the electricity grid;
- fostering more market-based investments in the sector, while decarbonising the EU energy system;
- introducing a new emissions limit for power plants eligible to receive subsidies;
- improving planning to anticipate and respond to electricity market crisis situations, including through cross-border cooperation.
# Short-term Wholesale Market Designs and Trends

## U.S. ISO Wholesale Markets
- Day-ahead hourly market
  - Energy
  - Ancillary services
  - Co-optimization of energy and AS
- Real-time 5-10 min markets
  - Energy
  - Ancillary services
- Both managed by ISO (centralized)
- Security-constrained bid-based dispatch
  - Energy markets integrated with congestion management
  - Locational marginal prices (LMP)
- Price caps ($1000 to $9000/MWh)
- Forward contracts and derivatives to hedge risks, meet resource adequacy and decarbonization obligations outside organize ISO markets
- Integrating new products (e.g. fast-start, storage) to respond to growing presence of intermittent wind/solar generation
- Expanding active participation by consumers

## European Wholesale Markets
- Diversity across countries operating under the same EU rules
- Day-ahead and intra-day hourly markets
  - Decentralized to independent power exchanges (PX) rather than TSOs (e.g. European Power Exchange, European Energy Exchange)
- Real-time markets managed by TSOs
  - Energy
  - Ancillary services
- Limited use of price caps (< €9,999)
- Limited integration of energy markets with congestion management
  - No LMP
  - Zonal separations and prices
  - Organized cross-border Market Coupling mechanism
- Integrating intermittent wind/solar with new products, intra-day adjustment markets
- Bilateral forward contracting and derivatives to hedge risks, meet supply security, and decarbonization obligations
- Expanding active participation by consumers
Generation Investment Incentives and Security of Supply

U.S.

- Forward Looking Resource Adequacy (RA) analysis (NERC/ISO)
  - Very low probability of lost load due to generation supply deficiencies (e.g. a few hours of small generation deficiencies in ten years)
- Resource adequacy obligations
  - Load serving entities (LSE)
  - ISO (centralized)
    - Capacity markets
    - Peaker net revenue benchmarks and “missing money”
  - Short-term energy market-based incentives relying on “scarcity pricing”
- Short-term energy market-based incentives (ERCOT)
  - Adders to energy prices based on administrative operating reserve demand curve (ORDC)
  - Price cap of $US 9,000/MWh
  - Alberta and Australia allow energy prices to rise to a price cap (no ORDC) without capacity obligation
- New approaches to capacity credits for wind, solar and storage from an SoS/RA perspective
- Efforts to increase transmission capacity to accommodate wind/solar (especially between balancing authorities)

Europe

- Forward looking Security of Supply (SoS) analysis by TSOs (e.g., RTE in France, National Grid ESO in England and Wales)
  - Very low probability of lost load due to generation supply deficiencies (e.g. a few hours of small generation deficiencies in ten years)
- Resource adequacy obligations
  - Load Serving Entities (binding and non-binding)
  - Some centralized responsibility (e.g. Great Britain, France)
  - None – leave it to the market
- Increased focus on security of supply (resource adequacy) in response to penetration of VRE to meet decarbonization goals
- Reluctance to add capacity remuneration mechanisms to energy market and forward contracting incentives
  - Peaker net revenue benchmarks and “missing money”
  - Cost of capital considerations
- A variety of capacity remuneration schemes have been introduced over time with a lot of variation across the EU
- New approaches to capacity credits for wind, solar and storage from an SoS/RA perspective
- Efforts to increase transmission capacity to accommodate wind/solar (especially between countries) and expand cross-border trade
Figure 36: CMs in Europe – 2019

Source: ACER Market Monitoring Report, February 2021
Figure 1-1: Wholesale Costs and Average Natural Gas Prices

Meeting Decarbonization Goals

**U.S.**
- No national U.S. climate policy
  - Several aggressive state initiatives
  - Limited regional carbon pricing
- Federal and State Subsidies for Wind and Solar (and other renewables)
- Renewable Portfolio Standards (RPS)
- Net metering for behind the meter (BTM) PV and storage
- Increasing use of long-term PPAs for zero-carbon resources via competitive auctions
- Evolving rules to integrate storage

**Europe**
- EU-wide policies implemented by individual countries
- Significant price on carbon emissions (EU ETS)
- Feed-in Tariffs for wind and solar
- Net metering for behind the meter (BTM) PV
- Increased use of long-term PPAs for zero carbon resources via competitive auctions (many more countries than just EU)
- Evolving rules to integrate storage
California’s Rolling Blackouts and Near Blackouts in August and September 2020
2020 STATISTICS

Peak renewables serving load
NEW RECORD

81.88%
May 2 at 1:40 p.m.

5-minute max

- Solar 49.6%
- Wind 23%
- Geothermal 5%
- Small hydro 1.8%
- Biomass 1.6%
- Biogas .9%
- Non-renewables 18.1%

Previous year:
80.3% on May 5 at 2:45 p.m.

Peak demand

47,236 MW
September 6 at 5:43 p.m.

5-minute average

- Natural gas 51.1%
- Imports 19.7%
- Large hydro 8.9%
- Renewables 15.4%
- Nuclear 4.8%

Previous year:
44,301 MW on August 15 at 5:50 p.m.

Source: CAISO
California Institutional Framework

• Several regulatory agencies
  • California Public Utilities Commission (CPUC)
  • California Energy Commission (CEC)
  • California Air Resources Board (CARB)
  • Federal Energy Regulatory Commission (FERC)

• California ISO (CAISO)
  • Manages day-ahead and real time markets using standard US-ISO market design
    • Price cap = $1,000/MWh (being raised)
    • Coordination with other control areas in the West
    • Limited responsibility for long term resource adequacy (security of supply)
    • No centralized capacity market
  • Transmission congestion management and long-term transmission planning
  • Covers about 80% of California System (LADWP and SMUD are separate balancing authorities)

• Resource Adequacy (RA) Obligations
  • Determined by CPUC
  • Assigned to load serving entities
    • Satisfied with PPAs with independent producers
    • CAISO oversight of performance of RA designated generators and demand response

• Retail supply competition
  • Very limited
  • But Community Choice Aggregation (CCA) has expanded
What Happened in August and September in California (CAISO)?

- Heat wave in California and nearby states in the West mid-August to early September
  - Heat waves are typical for this time of year but this one was at the top of the historical range and covered a wide area of theWSCC
- As a result of the heat wave electricity demand increased significantly in California and across the West in mid-August and early September (and again October 1-3)
  - Up to 47,000 MW peak demand on August 14 -19 and September 5,6,7
  - Previous peak 50,000 MW in 2006 and 2017 without blackouts
  - But VRE, especially solar, generation has increased a lot while 10,000MW of flexible gas capacity retired in the last few years
- CAISO has significant reliance on imports from outside but heat wave across the West reduced availability of import supplies
  - CAISO import/export rules are complicated
  - Western Energy Imbalance Market
- California has a complicated “resource adequacy” process driven by the CPUC rather than the ISO
Figure ES.1: July, August, and September Temperatures 1985 - 2020

Source: CEC Weather Data/CEC Analysis
This loop of the past four days features over 140 cases where observed temperatures either tied or broke their previous daily record highs. More record high temps are being set this afternoon with yet another round of record breaking heat expected across the Southwest tomorrow.

Source: https://twitter.com/NWSWPC/status/1295824180638670848
Actual and Near Rolling Blackouts

• Actual rolling blackouts only on August 14 and 15 and threatened rolling blackouts on August 17-19 and September 5-7, 2020
  • First rolling blackouts in California since 2001
  • August 14, OK solar generation day for the season (10 GW peak vs. 12 GW on good days in June/July), but a bit ragged, and relatively poor wind day
  • August 14, rolling blackouts 1000 MW for 2-3 hours ~ 6:30 to 8:30 PM
  • August 15, poor very ragged solar day and better wind day
  • But August 15 had sudden dip and then fast recovery in wind generation (~ 1200 MW), derating of NW transmission due to heat, loss of 470 MW fossil plant during evening net peak demand period
  • August 15, 1000 MW of rolling blackouts for only about 20 minutes starting at 6:30 PM
  • August 18 OK but very ragged solar day and better wind day for season. Formal and informal demand response. No blackouts.
• September 6 (4,000 MW generation deficiency forecast) Good solar and wind day for season. Formal and informal demand response. No blackouts
Table 3.1: CPUC-Jurisdictional Customers Affected by August 14 Rotating Outages

<table>
<thead>
<tr>
<th>Customers</th>
<th>CAISO-initiated rotating outage (MW)</th>
<th>IOU actual response (MW)</th>
<th>Time (in mins)</th>
<th>Start</th>
<th>Finish</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCE</td>
<td>132,000</td>
<td>400</td>
<td>400</td>
<td>63</td>
<td>6:56 PM</td>
</tr>
<tr>
<td>PG&amp;E</td>
<td>300,600</td>
<td>460</td>
<td>588</td>
<td>~150</td>
<td>6:38 PM</td>
</tr>
<tr>
<td>SDG&amp;E</td>
<td>59,000</td>
<td>71.6</td>
<td>84</td>
<td>~15-60</td>
<td>~9:08 PM</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>491,600</strong></td>
<td><strong>931.6</strong></td>
<td><strong>1,072</strong></td>
<td><strong>15 to 150 mins</strong></td>
<td></td>
</tr>
</tbody>
</table>

Source: CAISO
What Happened in August and September in California?

• Net demand rather than traditional peak demand overstressed generating resources

• Formal demand response programs, voluntary conservation, and emergency actions by the ISO appear to have played important roles in keeping rolling blackouts from being implemented on some of the Stage 2/3 Emergency days in mid-August and early September

• But Market Monitoring Committee (MMC) found that contribution of formal demand response programs appears to have been less than anticipated

• MMC has also concluded that wind and solar underperformed their RA values as gas capacity was derated by 3% due to heat

• Combination of exports and imports (at the same time) with different RA credits complicated operations and created some confusion about imports available

• The fires led to de-rating of one line from the NW at least on August 15 and a reduction in solar radiation a bit later.
Figure 4.3: Demand and Net Demand for August 14 and 15

4:56 pm: 46,802
6:51 pm: 42,237
5:37 pm: 44,957
6:26 pm: 41,138

CAISO
CAISO WIND GENERATION ON AUGUST 14 and 15, 2020

Generated with NRGStream Trader 8
CAISO Solar Generation on August 14 and August 15, 2020

Generated with NRGStream Trader 8
Smoke Effects on Solar Generation

Table 5.1: Day-Ahead Peak Forecast vs. Actual Peak During Heat Event (Updated)

<table>
<thead>
<tr>
<th>Date</th>
<th>Day-Ahead Peak forecast (MW)</th>
<th>Actual Peak (MW)</th>
<th>Difference (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>8/14/2020</td>
<td>46,257</td>
<td>46,802</td>
<td>545</td>
</tr>
<tr>
<td>8/15/2020</td>
<td>45,514</td>
<td>44,957</td>
<td>(557)</td>
</tr>
<tr>
<td>8/16/2020</td>
<td>44,395</td>
<td>43,816</td>
<td>(579)</td>
</tr>
<tr>
<td>8/17/2020</td>
<td>49,824</td>
<td>45,169</td>
<td>(4,655)</td>
</tr>
<tr>
<td>8/18/2020</td>
<td>50,484</td>
<td>47,120</td>
<td>(3,365)</td>
</tr>
<tr>
<td>8/19/2020</td>
<td>47,382</td>
<td>46,074</td>
<td>(1,308)</td>
</tr>
<tr>
<td>9/4/2020</td>
<td>41,009</td>
<td>40,674</td>
<td>(335)</td>
</tr>
<tr>
<td>9/5/2020</td>
<td>45,231</td>
<td>46,272</td>
<td>1,041</td>
</tr>
<tr>
<td>9/6/2020</td>
<td>49,166</td>
<td>46,887</td>
<td>(2,279)</td>
</tr>
<tr>
<td>9/7/2020</td>
<td>45,797</td>
<td>41,774</td>
<td>(4,023)</td>
</tr>
</tbody>
</table>
Figure B.4: August 14 Peak (4:56 p.m.) Unused RA Capacity by Resource Type

- Other
- Battery
- Geothermal
- DR
- Solar
- Wind
- Hydro
- Import
- Nat. gas

(MW)

- Derate
- No bid (no must offer)
- Partial bid (no must offer)
- Outage
- Transmission congestion
- Economics

Legend:
Real Time Prices SP15

Generated with NRGStream Trader 8
Day-ahead and Real Time Prices August 14, 2020

Generated with NRGStream Trader 8
Political Overreaction?

- Despite all of the attention and hand wringing, actual blackouts during the heat wave were relatively small (1000 MW) and of short duration
  - Extreme heat wave situation increased demand but capacity planning was based on 1 in 2 year peak demand and 15% administrative reserve margin
  - Not like 2001 when there were 38 days of rolling blackouts
  - Not like the pre-emptive “Public Safety Power Shutoff” and wild-fire-related events in 2017, 2018 and especially 2019 when millions of customers had their power cut often for several days to reduce the risk of fires
  - Not like outages after severe hurricanes in the East which can last days
  - But perhaps it’s a warning about the challenges for market-based systems which are heavily reliant on intermittent generation
What Happened in ERCOT (Texas) in February 2021?
Electric Generation, Transmission & Distribution Overview

ERCOt oversees the flow of power from power plants to substations.

- 51,667 MW Gas 47.45%
- 13,630 MW Coal 12.52%
- 5,153 MW Nuclear 4.73%
- 31,390 MW Wind 28.83%
- 6,177 MW Solar 5.67%

> 46,500 Miles of Transmission Lines

~ 5,000 Substations

~ 26 Million Texans

MW represent installed capacity
- 1,800+ active market participants that generate, move, buy, sell or use wholesale electricity
- 86,000+ megawatts (MW) of expected capacity for summer 2021 peak demand
- 710+ generating units, excluding PUNs
- Transmission projects endorsed in 2020 total $1.071 million
- 46,500+ miles of high-voltage transmission

- Wind Penetration record: 60.4 percent (Jan. 30, 2021)
- 25,121 MW of installed wind capacity as of Jan. 2021, the most of any state in the nation
- 3,854 MW of utility-scale installed solar capacity as of Jan. 2021
- 225 MW of installed battery storage as of Jan. 2021

<table>
<thead>
<tr>
<th>74,820 MW</th>
<th>73,821 MW</th>
</tr>
</thead>
</table>

1 MW of electricity can power about 200 Texas homes during periods of peak demand.

2021 Generating Capacity

- 51.0% Natural Gas
- 24.8% Wind
- 13.4% Coal
- 4.9% Nuclear
- 3.8% Solar
- 1.9% Other*
- 0.2% Storage

*Other includes hydro, biomass-fired units and DC tie capacity

2020 Energy Use

- 45.5% Natural Gas
- 22.8% Wind
- 17.9% Coal
- 10.9% Nuclear
- 2.9% Other*

381 billion kilowatt-hours of energy were used in 2020, a 0.5 percent decrease compared to 2019.

Source: ERCOT
Institutional Framework in Texas

- Texas Public Utility Commission (TPUC)
  - Regulates distribution and transmission companies
  - Manages retail supply competition framework
- Very limited Federal (FERC/DOE) regulatory authority
- ERCOT is an ISO with an independent board regulated by the TPUC (~ 90% of Texas)
  - Manages day-ahead and real time markets for energy and ancillary services
  - Standard short-term market design (LMP)
  - Transmission planning
  - Reliability assessments
  - Very limited interconnections with other supply areas
    - Limit Federal regulatory authority
- Resource Adequacy Obligations
  - None as such: No capacity obligations or capacity market
  - Rely on “scarcity pricing” in the energy market during tight supply situations
  - Sets administrative Operating Reserve Demand Curve (ORDC) to determine price adders during tight supply situation
    - $9,000/ MWh price cap (VOLL?)
  - Analysis underlying ORDC
    - Similar to the analytics underlying resource adequacy calculations in other areas
    - Integrates intermittency attributes of wind/solar (mostly wind to date)
    - “check-in” with more conventional reserve margin analysis
- Retail supply competition
  - Universal (except some municipal and cooperative utilities, e.g. City of Austin)
The Operating Reserve Demand Curve (ORDC)

- Price of Reserves ($/MWh)
- Available Reserves (MWs)

VOLL
ERCOT PRICE CAP

ERCOT
ERCOT PRICE DURATION CURVES
2014-2019
Highest 100 Hours

Source: Schneider and Goggin, Grid Strategies LLC, October 14, 2019, updated March 23, 2020
Real-Time LMPs for Load Zones and Trading Hubs Display

$LMP$ values do not include the Real-Time price adders.

<table>
<thead>
<tr>
<th>Settlement Point</th>
<th>LMP</th>
<th>5 Min Change to LMP</th>
<th>RTORPA + RTORDPA + LMP</th>
<th>5 Min Change to RTORPA + RTORDPA + LMP</th>
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</thead>
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<tr>
<td>HB_BUSAVG</td>
<td>1416.18</td>
<td>-54.11</td>
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<td>HB_HOUSTON</td>
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<td>-54.11</td>
<td>9,000.01</td>
<td>0.01</td>
</tr>
</tbody>
</table>

Last Updated: Feb 16, 2021 15:30:15
What Happened in ERCOT February 14-20, 2021?

- Extreme cold wave ("polar vortex"), rain, ice, snow affecting Texas and some adjacent areas (mostly to the East)
- Weather sensitive demand increased significantly but did not exceed worst case reliability assessment values
- Similar events in 2011 but much more extreme, widespread, or long-lasting
- Many failures on the supply side
  - Many generators (gas, coal, nuclear, wind) broke down as valves, control mechanisms, and turbines froze
  - Significant gas supply curtailments
    - Frozen equipment
    - Loss of electricity for compressors and gas/oil pumping
  - Some transmission failures due to freezing, wind, etc.
- Led to significant operating reserve deficiencies starting at about 1:00 AM on February 15
What Happened in ERCOT February 14-18, 2021?

• Operating reserve deficiencies triggered rolling blackouts starting at 1:20 AM on February 15
  • 10,400 MW initially
  • 20,000 MW later in the day
• Came close to a total system collapse on February 15 as frequency dropped below criterion
• Rolling blackouts continued into early February 19
  • About 5 million customers at a time dropped
  • PUCT ordered prices to be set at the price cap ($9,000) as long as there were rolling blackouts or brownouts
• Very large financial impacts on some generators and retail suppliers
  • Depends on hedging position
  • 20,000 MW with forward commitments out for three days = about $13 billion
  • Bankruptcy filings are starting
Rapid Decrease in Generation Causes Frequency Drop

- Entered EEA 3 1,000 MW Load-shed Ordered
- 35,343 MW Generation Capacity Out as of 1:23 am
- 1,418 MW Generation Outages 1:26am – 1:42am
- 248 MW Generation Outages
- 329 MW Generation Outages
- Additional 1,000 MW Load-Shed Ordered (Total 2,000 MW)
- Below 59.4 Hz for 4m 23s
  - More Gen Units would have tripped if below 59.4 for 9m or more
- 688 MW Generation Outages
- 511 MW Generation Outages
- Additional 3,000 MW Load-Shed Ordered (Total 5,000 MW)
- 606 MW Generation Outages
- 841 MW Generation Outages
- 843 MW Generation Outages
- 594 MW Generation Outages
- Additional 2,000 MW Load-Shed Ordered (Total 10,500 MW)
- Additional 3,500 MW Load-Shed Ordered (Total 8,500 MW)
- Min Frequency 59.302 Hz
Source: NRGStream Trader 8
Generation Capacity Out February 14 – 19, 2021

Peak Generation Out: 48.6%
(52,277 MW out of 107,514 MW total installed capacity)

- 25,000 MW of forced outages, including 14,000 MW of wind and solar
- 2,800 MW of planned outages, including seasonally mothballed capacity
Generation Capacity Out by Fuel Type

[Graph showing the generation capacity out by fuel type over a period of days, with different lines representing NG, Coal, Solar, Wind, Hydro, ESR, and Nuclear.]
ERCOT Wind and Solar Generation
February 10 – 22, 2021

Source: NRGStream Trader 8
Available Generation and Estimated Load Without Load Shed

Available Generation shown is the total HSL of Online Resources, including Quick Starts in OFFIQS. The total uses the current MW for Resources in Start-up, Shut-Down, and ONTEST.
Real-Time and Day-Ahead System-Wide Pricing

Average system-wide pricing around the event relative to other historical periods (in $/MWh)

<table>
<thead>
<tr>
<th>Date Range</th>
<th>Real-Time</th>
<th>Day-Ahead</th>
</tr>
</thead>
<tbody>
<tr>
<td>2/14/21</td>
<td>$6,579.59</td>
<td>$6,612.23</td>
</tr>
<tr>
<td>2/19/21</td>
<td></td>
<td></td>
</tr>
<tr>
<td>January '21</td>
<td>$20.79</td>
<td>$21.36</td>
</tr>
<tr>
<td>February '20</td>
<td>$18.27</td>
<td>$17.74</td>
</tr>
</tbody>
</table>

This data is using the ERCOT Hub Average 345-kV Hub prices
## 2011 vs. 2021 Event Comparison

<table>
<thead>
<tr>
<th>Metric</th>
<th>2011</th>
<th>2021</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum generation capacity forced out at any given time (MW)</td>
<td>14,702</td>
<td>52,277</td>
</tr>
<tr>
<td>Generation forced out one hour before start of EEA3 (MW)</td>
<td>1,182</td>
<td>2,489</td>
</tr>
<tr>
<td>Cumulative generation capacity forced out throughout the event (MW)</td>
<td>29,729</td>
<td>46,249*</td>
</tr>
<tr>
<td>Cumulative number of generators outaged throughout the event</td>
<td>193</td>
<td>356</td>
</tr>
<tr>
<td>Cumulative gas generation de-rated due to supply issues</td>
<td>1,282</td>
<td>9,323</td>
</tr>
<tr>
<td>Lowest frequency</td>
<td>59.58</td>
<td>59.30</td>
</tr>
<tr>
<td>Maximum load shed requested (MW)</td>
<td>4,000</td>
<td>20,000</td>
</tr>
<tr>
<td>Duration load shed request (hours)</td>
<td>7.5</td>
<td>70.5</td>
</tr>
<tr>
<td>Estimated peak load (without load shed)</td>
<td>59,000</td>
<td>76,819</td>
</tr>
</tbody>
</table>

*Note: “Cumulative” values for 2021 were calculated using NERC 2011 report methodology. Cumulative amount for 2021 starts at 00:01 on February 14, 2021.
Generation Weatherization

Generation owners and operators are not required to implement any minimum weatherization standard or perform an exhaustive review of cold weather vulnerability. No entity, including the PUC or ERCOT, has rules to enforce compliance with weatherization plans or enforce minimum weatherization standards.

In 2011, the PUC amended its rules to authorize ERCOT to conduct generator site visits to review compliance with weatherization plans. Spot checks include reviewing the weatherization plan, verifying that plant personnel are following the plan and providing recommendations based on PUC requirements, lessons learned or best practices.

We currently perform spot checks at power plant units at the rate of about 80/year. Whenever possible, a Texas Reliability Entity (TRE) representative joins ERCOT for these spot checks.

While we request and review detailed plant records, the only entity that can confirm that a plant is “weatherized” to any particular standard is the entity that owns or operates the plant.

Each year, TRE and ERCOT host an annual workshop on weatherization with generation owners to review lessons learned and best practices.
Lessons Learned from California and Texas

• Extreme weather events need to be given more attention in RA/SoS assessments and regulatory mechanisms
  • Capacity markets or ORDC alone do not automatically deal with changing weather patterns
  • Generating and transmission equipment can (will) fail under extreme weather conditions
  • Supporting regulatory rules may be necessary (e.g. weatherization, secondary fuel supplies)

• Resource Adequacy or SoS mechanisms need to be adapted to deep penetration of wind/solar generation to recognize and balance intermittency patterns
  • Net demand in all hours must be given much more attention
  • SoS goals and Decarbonization goals should be harmonized
  • Effective Load Carrying Capability (ELCC) is one approach
  • Similar “capacity derating” approach in England and Wales (National Grid ESO)

• Storage is becoming more and more important as carbon emissions constraints tighten and penetration of intermittent generation grows
  • Effectively integrating storage into the wholesale market requires well-functioning short-term energy markets
  • Storage is being integrated into capacity markets (see March 2, 2021 capacity market results in England and Wales)

• Expanding price sensitive demand response will become more important over time as intermittent generation expands
  • Politics and economics may clash here
  • Practical tradeoffs between incentive effects and redistributive effects
  • Forward contracting will become more important than very high spot market prices

• Adequate supplies of fast-response generation and storage is required to manage intermittency without causing reliability problems
  • Supporting market mechanisms are on the front burner

• Inter-regional trading rules need to recognize extreme events
  • California
  • Texas
  • England and Wales
Advances in Demand Response

- Responses to calls for voluntary conservation and activation of formal demand response programs appear to have averted more blackouts in California though formal demand response underperformed
  - Demand response will become more and more important in high-VRE/EV systems but there are limits to the effects of calls for voluntary conservation
  - Advanced metering and communications technology is not being used effectively --- opportunities to integrate BTM PV, storage and EV in demand response programs and wholesale markets
  - Need to better link wholesale market prices with retail prices, though TOU tariff changes are a step in the right direction
Security of Supply Calculations and Support Mechanisms

• High VRE system require new approaches to Security of Supply (resource adequacy) which reflect variability of supplies from intermittent generation
  • Intermittency
  • Ramping
  • Fast-response thermal (on the way to 100% carbon free)
  • Storage (short-term, long-term)
<table>
<thead>
<tr>
<th>Region</th>
<th>BTM PV</th>
<th>Fixed PV</th>
<th>Tracking PV</th>
<th>Tracking PV Hybrid</th>
<th>Wind</th>
<th>Wind Hybrid</th>
</tr>
</thead>
<tbody>
<tr>
<td>PGE</td>
<td>4.3%</td>
<td>5.4%</td>
<td>6.9%</td>
<td>99.6%</td>
<td>21.8%</td>
<td>54.0%</td>
</tr>
<tr>
<td>SCE/SDGE</td>
<td>3.6%</td>
<td>4.6%</td>
<td>5.4%</td>
<td>99.9%</td>
<td>18.0%</td>
<td>47.0%</td>
</tr>
<tr>
<td>AZ APS</td>
<td></td>
<td></td>
<td></td>
<td>99.0%</td>
<td>38.8%</td>
<td>78.3%</td>
</tr>
<tr>
<td>NM EPE</td>
<td></td>
<td></td>
<td></td>
<td>99.0%</td>
<td>38.8%</td>
<td>78.3%</td>
</tr>
<tr>
<td>BPA</td>
<td></td>
<td></td>
<td></td>
<td>32.7%</td>
<td>57.2%</td>
<td></td>
</tr>
<tr>
<td>CAISO</td>
<td>4.0%</td>
<td>5.0%</td>
<td>6.2%</td>
<td>99.8%</td>
<td>19.9%</td>
<td>50.5%</td>
</tr>
<tr>
<td>Average</td>
<td>4.0%</td>
<td>4.8%</td>
<td>5.8%</td>
<td>99.4%</td>
<td>30.0%</td>
<td>62.0%</td>
</tr>
</tbody>
</table>

Table ES2. Recommended ELCC Values for 2026

<table>
<thead>
<tr>
<th>Region</th>
<th>BTM PV</th>
<th>Fixed PV</th>
<th>Tracking PV</th>
<th>Tracking PV Hybrid</th>
<th>Wind</th>
<th>Wind Hybrid</th>
</tr>
</thead>
<tbody>
<tr>
<td>PGE</td>
<td>1.3%</td>
<td>2.1%</td>
<td>3.4%</td>
<td>98.8%</td>
<td>17.9%</td>
<td>43.5%</td>
</tr>
<tr>
<td>SCE/SDGE</td>
<td>0.6%</td>
<td>1.2%</td>
<td>1.9%</td>
<td>96.4%</td>
<td>17.8%</td>
<td>35.3%</td>
</tr>
<tr>
<td>AZ APS</td>
<td></td>
<td>~0.0%</td>
<td>1.9%</td>
<td>96.0%</td>
<td>30.8%</td>
<td>79.2%</td>
</tr>
<tr>
<td>NM EPE</td>
<td></td>
<td>~0.0%</td>
<td>1.9%</td>
<td>96.0%</td>
<td>30.8%</td>
<td>79.2%</td>
</tr>
<tr>
<td>BPA</td>
<td></td>
<td></td>
<td></td>
<td>32.8%</td>
<td>52.8%</td>
<td></td>
</tr>
<tr>
<td>CAISO</td>
<td>1.0%</td>
<td>1.7%</td>
<td>2.7%</td>
<td>97.6%</td>
<td>17.9%</td>
<td>39.4%</td>
</tr>
<tr>
<td>Average</td>
<td>1.0%</td>
<td>0.8%</td>
<td>2.3%</td>
<td>96.8%</td>
<td>26.0%</td>
<td>58.0%</td>
</tr>
</tbody>
</table>
## Storage in UK Capacity Markets

<table>
<thead>
<tr>
<th>Storage by duration in hours for T-1 and T-4 auctions(^{26})</th>
<th>Conversion of imported electricity into a form of energy which can be stored and the re-conversion of the stored energy into electrical energy. Includes hydro Generating Units which form part of a Storage Facility (pumped storage), compressed air and battery storage technologies.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Dur.a'n:</strong></td>
<td><strong>T-1:</strong></td>
</tr>
<tr>
<td>0.5hrs</td>
<td>21.34%</td>
</tr>
<tr>
<td>1.0hrs</td>
<td>40.41%</td>
</tr>
<tr>
<td>1.5hrs</td>
<td>55.95%</td>
</tr>
<tr>
<td>2.0hrs</td>
<td>68.05%</td>
</tr>
<tr>
<td>2.5hrs</td>
<td>77.27%</td>
</tr>
<tr>
<td>3.0hrs</td>
<td>82.63%</td>
</tr>
<tr>
<td>3.5hrs</td>
<td>85.74%</td>
</tr>
<tr>
<td>4.0+hrs</td>
<td>96.11%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>Dur.a'n:</strong></th>
<th><strong>T-1:</strong></th>
<th><strong>T-4:</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>0.5hrs</td>
<td>17.50%</td>
<td>14.91%</td>
</tr>
<tr>
<td>1.0hrs</td>
<td>34.21%</td>
<td>29.40%</td>
</tr>
<tr>
<td>1.5hrs</td>
<td>50.00%</td>
<td>43.57%</td>
</tr>
<tr>
<td>2.0hrs</td>
<td>62.80%</td>
<td>56.68%</td>
</tr>
<tr>
<td>2.5hrs</td>
<td>71.96%</td>
<td>66.82%</td>
</tr>
<tr>
<td>3.0hrs</td>
<td>78.09%</td>
<td>73.76%</td>
</tr>
<tr>
<td>3.5hrs</td>
<td>81.57%</td>
<td>77.78%</td>
</tr>
<tr>
<td>4.0hrs</td>
<td>95.52%</td>
<td>80.00%</td>
</tr>
<tr>
<td>4.5+hrs</td>
<td>95.52%</td>
<td>95.52%</td>
</tr>
</tbody>
</table>

---

National Grid EMR 2018 Capacity Market Report, May 31, 2018